03-07-05

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

---- In the Matter of ----)
)
PUBLIC UTILITIES COMMISSION) DOCKET NO. 03-0371
)
Instituting a Proceeding to Investigate)
Distributed Generation in Hawaii)
)

POST HEARING OPENING BRIEF

OF THE

HAWAII RENEWABLE ENERGY ALLIANCE

AND

CERTIFICATE OF SERVICE

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I. INTRODUCTION AND SUMMARY

The Hawaii Renewable Energy Alliance hereby submits its Post-Hearing Opening Brief, dated March 7, 2005, to the Public Utilities Commission (PUC), in accordance with the PUC's Prehearing Order Number 20922 (Reference Docket No. 03-0371).

HREA believes there is consensus among the parties that DG can provide: (1) renewable energy and more efficient use of fossil fuels to generate electricity, thus contributing to our state goal of reducing our fossil energy use, (2) energy cost savings to DG users and overall benefits to the utility grids and our economy, and (3) the opportunity, through increased competition, to provide a measure of relieve to Hawaii's ratepayers.

HREA also believes, after a thorough review and discussion of all the key issues of this docket, Hawaii's electricity market will be best served by implementing DG via the structured competition model that we first proposed in our Direct Testimony T-1.

HREA believes a PUC ruling supporting implementation of HREA's proposed structured competition model is desirable for the following reasons: (1) utility[1] direct participation in the DG market is inappropriate, unprecedented and will heavily tilt the field in their favor, (2) in contrast, utility facilitation will result in a greater number of DG systems installed in a given period of time, and (3) potential rate impacts on non-DG customers will be mitigated, especially times of capacity shortfalls, as DG systems installed will offset new load requirements.

HREA has organized the remaining sections of this opening brief as follows:

1. Section II - HREA's Response to PUC Questions – reference PUC letter, dated December 28, 2004 to all Parties. This letter included seven questions, and a solicitation for an other questions the parties and participants wished the PUC to consider;

2. Section III – HREA's Additional Considerations for the PUC – including the context in which the DG docket decision and order will be made and the relevance of the DG docket to Hawaii's Energy Future.

3. Section IIV – HREA's re-stated Statement of Position (SOP) – a summary of our SOP based on HREA's participation and learning on this docket.

II. HREA's Response to PUC Questions

From the Commission's letter, dated December 28, 2004: The Commission requests that the Parties and Participants address the following issues in their post-hearing opening briefs, in addition to any other questions the parties and participants wish the Commission to consider:

1. Whether the costs and benefits of distributed generation change in times of excess capacity vs. times of shortages of capacity; if the answer is yes, given that for the life of any long-term asset there are likely to be periods of excess capacity and shortages, please comment on the time span over which one should measure the costs and benefits of distributed generation;

HREA's Response:

HREA does not believe the **costs** of distributed generation would necessarily change in times of excess capacity vs. times of shortages of capacity. Instead, we believe that the costs would be driven by basic market factors, and the costs of DG technologies will change over time. For some, such as renewables, installed system costs have been decreasing and will continue to decrease over time. Generally, the results of technical and economic analyses are that costs will level off for specific technologies as they mature. Of course, in the long run as

[1] Subject to further discussion, HREA believes that the Kauai Island Utility Cooperative should be treated separately, certainly in the short-term, given that they have excess capacity on their system.

the learning in manufacturing, installation and operation practices has been optimized, the effective cost of energy from these technologies, as well as many current energy technologies, trend upward as material and labor costs increase. For fossil DG, installed costs may also decline over some time period, while fuel costs will trend upward with uncertain volatility in price and supply. Consequently, as new renewable technologies emerge, HREA believes they will supplant fossil DG, due in large part, to the increasing fuel and other operating costs of fossil DG.

On the other hand, HREA believes the **benefits** to the customer installing on-site generation, the utility, the remaining ratepayers, and the overall economy will change during times of excess capacity versus times of shortages of capacity.

In times of excess capacity, HREA believes there will be specific benefits to the **customer** and to the **economy** independent of who owns and operates the DG. Excess capacity situations are likely to be caused by a utility's installation of large central generation units designed to serve several years of future load growth, replace existing aging units or expiring contracts with IPPs. Frequently the installation of a major new central generation unit will be accompanied by the utility's request for a substantial rate increase. The benefits to the customer installing self-generation are greatest when the rate increase goes into effect. However, once the utility has installed the central generation (CG), it will have not incentive to install utility-owned, customer-sited DG for several years, until the island's markets have "grown in" to the CG. Meanwhile, independent developers of DG will be unable to survive the "boom and bust" cycles of utility demand for or rejection of DG, and will depart the islands, leaving the customers seeking an alternative to high utility rates few or no options. The economy will become less diversified as these entities leave Hawaii.

In times of excess capacity, the benefits to the **utility** of installing DG disappear. The benefits to the remaining **ratepayers** are diminished, but some continue in effect. Specifically

a. Assuming first that the **DG is non-utility**, there will be less value to the **utility**, given the potential of non-utility investments to strand a portion of existing utility generation investment for the "growing in" period, especially if the utility's generation portfolio does not allow flexibility, and lose revenues. We still believe there will be some value to the remaining **ratepayers**, if the DG is non-utility. Specifically, DG investments would not go into utility rate-base and it is questionable whether utility revenue losses will, by themselves, cause the utility to file with the Commission to increase rates, especially during a growth period that caused the need for the new unit in the first place. For example, the remaining ratepayers would not only escape paying for the DG investment, but would also experience lower overall variable system costs, such as operating and maintenance costs and especially all fuel costs;

b. For the utility to install and own customer-sited DG for an existing customer in a time of excess capacity would be (1) imprudent, or (2) an indication that the utility's rates were too high to meet the competition, so that these rates must be redesigned to eliminate cross-subsidies and lowered to the actual costs to serve the customer or customer class. Otherwise, the remaining ratepayers would be improperly be cross-subsidizing the preferred customer enjoying the utility-owned, customer-sited DG.

In times of <u>capacity shortfall</u>, HREA believes there will be specific benefits to the **customer** independent of who owns and operates the DG. The customer will receive potentially more reliable power at an overall cost that is lower than the utility's standard rate. Also, regardless of the DG ownership, the benefits will have a higher value to the **utility** and the remaining **ratepayers**, as there would be the potential to defer new generation requirements. However, the benefits to the remaining ratepayers would change depending on DG ownership:

a. Assuming that the **DG is non-utility**, HREA does not believe there will be major adverse impacts to the remaining ratepayers due to utility revenue losses between rate cases. In a new rate case the utility will have the opportunity to take load growth into account to offset the load lost to self-generation in setting its rates, and to adjust existing rate class cross subsidies in such a way as to increase the likelihood that it can retain the load being lost to DG in the future. Further, the utility can modify the extent to which fixed costs are being recovered in its energy charge, and diminish its own risk of revenue shortfall if additional customers decide to self-generate in the future. In the mean time, both the utility and non-utility providers have the opportunity to compete to serve new load; and

b. On the other hand, if the **DG is utility**, the remaining ratepayers would have to pay for the utility's generation investments, operating costs and especially all fuel costs, in exchange for whatever very limited system benefits in system reliability, contribution to fixed costs by the DG customer, and generation deferral that can be quantified.

Regarding the time span, HREA believes that each individual customer considering the installation of on-site generation should be allowed to make its own determination of the time horizon over which it decides to measure costs and benefits. In this regard, flexible tem provisions in contracts with DG providers should be available to the customers. If the DG is going to be owned by a utility for grid support or purchased from an IPP for general system supply, however, HREA recommends a 20-year period for measuring the costs and benefits of DG to correspond with the utility's 20-year planning horizon in IRP.

2. How should non-utility owned distributed generation be incorporated into the IRP process, in a manner comparable to the treatment of utility-owned distributed generation, so that there is no market or regulatory advantage of one type over another?

HREA's Response:

In order to answer this question, HREA would like to discuss the treatment of DG as demand-side management (DSM) alternatives versus supply-side management (SSM) alternatives. Subsequently, we recommend that utility (should that be allowed) and non-utility owned DG be treated the same as follows.

<u>DSM Alternatives</u>. HREA believes all DG on the customer-side of the meter, whether utility-owned (should that be allowed) or non-utility, should be incorporated under the DSM program in IRP, at locations on the system where IRP has shown that it is needed, to the extent that is possible. The costs and benefits of DG-DSM's should be evaluated along with all other DSM's. HREA believes further that specific DSM program elements should be tailored for each desired technology on each of our island grids. Following the structured competition market model that HREA has proposed, the utility would market and facilitate each DSM program element in a similar manner to what is done on existing programs, such as for solar hot water (SHW) systems. Finally, incentives could be designed and utilized to level the field among all DG-DSM technologies.

<u>SSM Alternatives</u>. HREA believes all DG on the utility-side of the meter, whether utility-owned or non-utility (should that be allowed), should be incorporated under the SSM program in IRP. This applies whether the DG is being used for grid support (e.g., at substations, for voltage regulation, etc.) or in a traditional supply function (e.g., firm or non-firm supply, peak shaving, etc.). The costs and benefits of DG-DSM's should be evaluated along with all other SSM's. Since HREA supports competitive bidding on all supply-side resources, HREA believes the utility should acquire all SSM's, including DGs, via a competitive bidding process.

Identifying Load Pockets. It may be possible to identify specific load pockets needful of DG support (as has been suggested by the CA and HREA). If so, the utility could then solicit proposals to offset specific loads that had been identified. If it is not possible, the utility could create DG-DSM programs for specific technologies to offset the aggregate load, in a similar manner as is done on the SHW DSM.

Overall Planning. Regarding the overall planning in IRP, HREA believes that estimates of the desired DG-DSMs, whether including individual load packets or only in the aggregate, would be provided as inputs to adjust the demand forecast for each of our island grids. HREA believes this is exactly the approach already in place on the SHW-DSM program element. This approach can serve as the model for incorporating new DSM program elements for DG, including CHP.

3. Whether transmission and distribution costs will be substantially reduced for (sic) CHP or other distributed generation projects set up for peak-shaving only;

HREA's Response:

For economic and other reasons, customer-sited CHP is generally operated in accordance with the customer's need for the heat energy and does not export electrical energy to the grid, and therefore is not suitable for shaving of the utility system's peak load. In some cases HECO is proposing to override the customer's dispatch of its CHP units to call for increased operation during HECO's peak periods, to minimize the customer's demand for supplemental energy supplied by the grid at that time. This option appears to have limited potential to affect the system peak and can only be used rarely if the customer is to receive the guaranteed savings floor described in Docket No. 03-0366.

Other forms of fossil-fired DG, such as straight diesel located at customer sites (e.g., making use of emergency diesel generation owned by hospitals and others in a "virtual power plant mode) could provide peak-shaving options, if such operation were allowed under current

Firm renewable DG, such as pumped hydro, can be used for peak shaving. Non-firm renewable DG can be called upon for peak shaving, but may or may not be available that at critical times. In general, peak shaving avoids generation costs, not transmission and distribution costs, although in some load bottleneck situations DG can reduce transmission and distribution costs at peak. In general, however, DG at customer sites is used to substitute for baseload utility power and to address the customer's peak, rather than the utility system's peak.

Nevertheless, HREA believes that T&D losses can be reduced through the implementation of CHP and DG projects in general, but particularly for those projects that are designed to run at peak times, which will help shave the peak loads on each of our island grids. We believe that these loss reductions will also result in savings in the O&M of T&D facilities. There will also be the opportunity to avoid new T&D upgrades in areas where the T&D is already near capacity. Finally, HREA believes the discussion on this topic during the pleadings and the hearing supports our beliefs. However, HREA is not in a position at this time to conclude if the T&D savings will be substantial, and defers to other Parties who may be in a better position to quantify the T&D cost savings.

4. Whether potential loss of revenues to investor owned utilities (IOUs), due to advancements in technology and the development of new markets is a risk for which the utility has been and is compensated through its approved rate of return; and which forms of distributed generation, if any, would fall into the category of advancement risks for which the utility already receives compensation;

HREA's Response:

We believe that potential loss of revenues to investor owned utilities (IOUs), in general, is a risk for which the utility has been and is compensated through its approved rate of return, subject to the decision and order for specific rate cases. The question is whether the risks associated with DG should be included in the category of advancement risks for which the utility already receives compensation?

HREA believes this is a very important question and one that needs to be addressed as we look to the future of our electricity market in Hawaii. HREA would agree that perhaps certain risks should be included, such as utility implementation (if approved) of supply-side DG. However, we question whether any risks should be included for demand-side DG, regardless of ownership.

Risks Associated with Implementing DG. There are attendant risks with implementing advanced technologies, such as CHP, in Hawaii's market and we do not believe it is in the ratepayers' interest for the utility to take on those commercial risks and subsequently pass them on to the ratepayer. HREA believes that the innovation required to introduce new technologies in the electricity market is best accomplished by industry, not the utility.

Who Pays for DG Losses? As discussed in this proceeding, HECO's venture into the wind business was via an unregulated affiliate, Hawaii Renewable Energy Systems (HERS). As it turned out, HERS's operational losses were absorbed not by HECO's ratepayers, but by HEI's stockholders. This is clearly an example of a DG that was considered risky and not pursued by the regulated IOU. On the other hand, HECO will likely seek to have the costs of its proposed CHP program incorporated into their rate base. Thus, the ratepayer would absorb all risks from this venture. HREA **CAN** support HECO's current efforts, if the efforts are all oriented towards preparing the company for facilitating the CHP market, but we **CANNOT** support ratebasing their efforts, if they are allowed to compete with industry. Therefore, utility involvement in the CHP (or other DG) market (s) should not be allowed. As we have stated previously, should the utility wish to enter the DG market, HREA supports their participation via an unregulated utility-affiliate.

Risks Associated with Implementing Non-Utility DG. More importantly, as competition in the market evolves, potential revenue losses could become an issue to the IOUs, their shareholders and their ratepayers. HREA believes the important question to be resolved is whether the ratepayers have an obligation to keep the company "whole" as the market changes? The utility must bear some of the responsibility to manage its costs so that its rates are competitive with available alternatives. If the goal is to keep the company "whole,"—that is, earning its allowed return on every single kWh consumed in its service territory -- the ratepayers would end up footing the bill, once again. However, if the goal is to diversify our electricity market via competitive implementation of DG, one of the few competitive alternatives that are feasible in our small, remote, island markets, the ratepayers are justified in receiving the benefits and not having to pay for the utility's revenues losses from non-utility DG. Thus, HREA believes the IOU should have the opportunity to earn a profit, but not to be guaranteed that they will continue to be made "whole."

5. Whether the utility would have stranded costs in period (sic) of load growth.

HREA's Response:

HREA does not believe the utility would have stranded costs in periods of load growth if it were barred from entering into the market for behind-the-meter, customer-sited DG. The utility's existing central generating assets would generally continue to be utilized at or very near capacity, such that their capacity costs will be recovered from their remaining ratepayers. Any future generation that the utility might install could be sized to take into account third-party owned generation. With respect to transmission and distribution costs, again HREA does not anticipate that the utility would incur stranded costs. Assuming that the utility has correctly applied its Rule 13 to limit the amount of subsidy existing customers afford to a customer being added to the system, the customer will have paid for any excess transmission and distribution costs when it came on to the system. The distribution lines paid for in part by the customers are donated to the utility, thereby facilitating the utility's ability to add more new customers. Also, in many cases existing customers installing non-utility DG will remain on the system to take standby and scheduled maintenance from the utility, so that the utility will continue to receive revenues from the customer. These revenues, too, would prevent the stranding of facilities costs.

"Stranded costs" is used on the mainland to describe costs of facilities approved by the Commission and built to accommodate customer load that does not materialize. In this proceeding, however, HECO has referred to fixed costs embedded in the energy charge of its larger customers that are lost to non-utility DG as "stranded costs." If the loss of load is such that the utility does not meet the annual sales levels on which the billing determinants used in designing its rates is based, then the utility suffers (albeit less so in a period of load growth) until its next rate case. In the new case it can reset its billing determinants, reduce the interclass cross subsidies that led to its inflated energy charges, and redesign its rates to include more of the fixed costs in the customer and demand charges. Accordingly, any revenue shortfall between rate cases should not be treated as a special category of "stranded costs," but should be handled in the ordinary course, with no particular adjustment to rate of return for competitive risk.

6. Is it reasonable to expect identification of individual projects or project zones in the IRP process? What specific modifications to the IRP process should the Commission consider to facilitate such identification?

HREA's Response:

The Parties have had considerable discussion on this question. HREA's assessment is that the CA, HREA and perhaps other Parties believe it is possible to identify specific projects or project zones (also referred to as load pockets) in the IRP process. For example, it may be possible to identify specific load pockets at both the transmission and distribution (T&D) levels, given that utility planners already monitor utility T&D assets in order to determine when upgrades are needed. HREA believes this planning process could provide signals for DG projects. However, HECO testimony (in particular Shari Ishikawa) contradicts HREA's belief, suggesting, at best, it would be difficult. HREA suggests that if the utility were to be prohibited from owning and including in rate base future generation of any size, as has occurred in many mainland states' restructuring plans, the utility would become more willing to devise a planning process and competitive bidding scheme that would facilitate the installation of needed generation by others.

Upon further reflection, it may not matter whether individual load pockets that could benefit from the installation of DG can be identified, as HECO's current approach or interpretation of the IRP Framework is to identify an overall potential (in aggregate) market for DG (e.g., CHP) on their system. This is similar to HECO's approach for SHW-DSM, i.e., there is an estimate of how many systems will go in each year, what the average load and energy off-sets would be, etc. These results are then used to adjust the load forecast. For example, peak load demand is reduced by the amount of expected SHW-DSM. Consequently, HREA believes the same approach could be used for all DG-DSMs, including CHP.

HREA notes that using this DG-DSM approach would be a departure from current practice in IRP. However, HREA believes that this approach would be relatively straightforward to implement. See also our response to question 2 above.

7. Under each of the two scenarios for participation in distributed generation – utility participation and utility affiliate participation – what rules and restrictions are necessary to assure that the competition between non-utility projects and utility-owned (or affiliate-owned) projects is evenhanded, meaning that the utility or utility affiliate has no unearned competitive advantage? (Note: although some Parities and Participants may believe that there is no possibility of unearned competitive advantage, while other Parties and Participants might believe that any participation by the utility or an affiliate will distort the market, the Commission urges Parties and participants to suspend these beliefs for the purposes of this question and assist the Commission's consideration of practical approaches.)

HREA's Response:

HREA believes there are primarily two sets of issues to resolve: technical and administrative.

Regarding the <u>technical issues</u>, HREA believes that the requirements for interconnection, including safety, reliability and operation, placed on DG should be the same for all DG, i.e., utility and non-utility, including utility affiliate. Consequently, all DG would need to meet the same interconnection requirements -- those currently in place, or as revised in the future. Note: with regards to HECO's proposed CHP program, HECO has stated that they would not install systems that would export power to the grid. Consequently, technical requirements issues may emerge, should a non-utility (third party) or utility-affiliate wish to export power to the grid. Specifically, would additional technical requirements be placed on the utility-affiliate and third parties? HREA has identified as a barrier in our DT-1[2] and during the Hearing[3], where Warren Bollmeier identified the need for an optional section for a power purchase agreement in a CHP interconnection agreement.

Regarding the administrative issues, HREA has already stated concerns about conflicts of interest between the utility and third parties, if the utility is allowed to participate directly in the DG market. In that case, it would most likely fall on the PUC to ensure that the utility was acting in a non-discriminatory manner. HREA concurs with Jim Lazar[4], that it would take a significant effort with potential heavy-handed enforcement measures to ensure assure that the competition between non-utility projects and utility-owned (or affiliate-owned) projects is even-handed. If the Commission decides to go this route, HREA recommends that the Commission issue a detailed proposed rule and let affected parties comment on it.

HREA believes appropriate firewalls can be established between the utility and a utility-affiliate. REA believes there will be a manageable effort required of the PUC and CA to ensure that the utility-affiliate benefits in no way from the parent utility separate from third parties. Finally, we believe, there will be need for a dispute resolution procedure that is timely and not costly to third parties, should there be a need to address allegations of impropriety.

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[2] HREA T-1 Direct Testimony, page 10.
[3] Hearing, Day 2, Panel F, reference: pages 175 to 177 of the Day 2 transcripts.
[4] Hearing, Day 2, Panel C, reference: page 23:22 to page 24:5 of the Day 2 transcripts.

III. <u>HREA's Additional Considerations for the PUC</u>

HREA recommends that the Commission consider the overall context ("The Big Picture") in which the issues of this docket will be resolved, and, specifically, how the results of this docket may impact the Hawaii's energy future. In this regard, HREA would like to offer the following for consideration:

Context ("The Big Picture")

HREA believes the resolution of the issues on this docket can do one of two things:

(1) Support the continuation of "<u>business as usual</u>" within the existing utility paradigm in which utility profits are driven by sales and the incumbent utility wards off all forms of competition – in which case, utility control of the electricity market will remain supreme, or

(2) Initiate a shift towards a <u>new utility paradigm</u> where competition is encouraged and utility profits are no longer driven by sales of fossil electricity – in which case, the utility will be incentivized to reduce our dependence on imported fossil energy, supporting our state energy goals to, and hopefully, in the process, helping to stabilize utility rates initially and then reduce rates over the longer term.

Simply stated, under option (1) the utility would be allowed to participate directly in the DG market, whereas they would not be allowed to participate directly in the DG market in option (2). In essence, option (2) represents market reform, which would support the innovation and competition that is needed to meet our state's energy goals and, at the same time, provide a measure of relief to ratepayers.

So how could this happen? How could the Commission's actions facilitate the process? Let's talk first about Hawaii's Energy Future.

Hawaii's Energy Future

HREA believes a good starting point is to establish a common vision. Such a vision has been created by the Hawaii Energy Policy Forum as follows:

> "Hawaii will have environmentally friendly, renewable, safe, reliable, and affordable energy resources. Our energy technology and systems will be efficient, with the best available emission controls; decentralized; meet consumers' needs; and maximize the use of Hawai'i's energy assets. Hawai'i will encourage investment in energy system development and continually assess energy development options based on a full accounting of costs and benefits."[5]

HREA notes that similar visions have been discussed and advanced in Hawaii for some time, certainly going back at least to the CON-CON in 1978. However, there has never been a consensus on how to proceed. We continue to get hung up on what do, how fast to proceed and, most importantly, who is in charge, or some might say simply that we have lacked the political will to do the right thing. In any case, HREA believes there is a growing awareness of our energy problems, our vulnerability and an emerging consensus that we need to move aggressively forward and now. The question continues to be "how best to gain consensus and move forward?"

In order to answer that question, in essence, to implement the vision, HREA believes we need two things, both of which are currently missing:

(1) An integrated energy policy – such a policy would cover all energy sectors, of course, but for the purpose of this discussion, HREA would like to focus on the electricity sector. We observe that we have parts of an integrated energy policy in place, for example, the Renewable Portfolio Standards (RPS), net energy metering and renewable energy tax credits. There are other potential elements, such as the DG policy decisions to be made on this docket and utility DSM programs. More importantly, the existing policies are not integrated, e.g., there are a number of pieces, but are they connected, how are they connected, are we getting the best benefit from taxpayer and ratepayer contributions, etc? For

example, HREA views RPS as a broad policy measure, which requires the utility to provide X% of its net electricity sales over time from renewable sources, whereas the tax credits encourage private investment in certain technologies. Are they connected? How are they connected? Tax credits can support the RPS, but so can other policies, such as net metering and other possible policy options, such as an electricity feed law. So how do all these policies fit together? Some of them do, but if they were integrated into an overall energy policy for the state, we would be better able to optimize their use and get the maximum benefit from taxpayer and ratepayer contributions.

(2) An integrated energy implementation plan – once we have an integrated energy policy, we need a plan to implement the policies. One might say the RPS represents such a plan. Others would say, no, it is only a policy. Yet our RPS law is remarkably silent on how the RPS is to be implemented. It is implied that the utilities will make it so, thus placing the utility in the position of implementing state policy. And what is the relationship to other broad policy measures, such as an energy efficiency portfolio standard, energy security measures, or a Kyoto-style emission reduction program? For this discussion, let's assume, again, that we have an integrated energy policy consisting of Y major policy elements. The implementation plan would include of specific actions to implement each policy element, and how each action and policy element supports each other. Again, the Hawaii Energy Policy Forum has broken some ground in this area. Specifically, following a number of studies to update our energy options, the Forum has prepared a long-term energy strategy.[6] This document is a potential starting point for the integrated energy implementation plan.

[5] Reference: http://hawaiienergypolicy.hawaii.edu/pages/vision.html.

So what does this all mean to the DG Docket?

This is a fair and important question. For starters, this docket's purpose is not to create an integrated energy policy or implementation plan for Hawaii's electricity sector. However, there is the opportunity to create an integrated policy and implementation plan for DG, which could become an important part of a future integrated energy implementation plan. In fact, through its actions on this docket, the Commission has the opportunity to help lead the way to such plan. How so? Let's take another look at the vision:

> "Hawaii will have environmentally friendly, renewable, safe, reliable, and affordable energy resources. Our energy technology and systems will be efficient, with the best available emission controls; decentralized; meet consumers' needs; and maximize the use of Hawai'i's energy assets. Hawai'i will encourage investment in energy system development and continually assess energy development options based on a full accounting of costs and benefits."

HREA is quite certain that we have discussed all the above underlined attributes in our search for how to structure and implement the DG market. Furthermore, each of these attributes comport with our state energy policy.

Therefore, as the Commission deliberates its decision and order for this docket, HREA recommends that the Commission determine which market structure will give us the best chance of implementing the vision. In conclusion, HREA believes the Commission now has most, if not all, of the information needed to determine the elements necessary to assemble an integrated DG policy and implementation plan that would be rooted firmly in IRP.

[6] Reference: http://hawaiienergypolicy.hawaii.edu/papers/HEPStrategy.pdf

IV. HREA's Re-Stated Statement of Position

The following is HREA's re-stated position on the issues, which were first presented to the Parties on pages 2 and 3 in the Prehearing Order and discussed in the subsequent pleadings and the hearing.

Planning Issues:

Overall: HREA believes planning issues are important, as they set the stage for the design and implementation of the DG market place.

1. **What forms of distributed generation (e.g., renewable energy facilities, hybrid renewable energy systems, generation, cogeneration) are feasible and viable for Hawaii?**

HREA's Re-Stated Position:

Referencing our Preliminary SOP, it is clear that certain DGs can make an immediate impact: certainly fossil CHP and other fossil DG, solar and wind. HREA believes it is important to look at whether the DG will be on the customer-side of the meter or the utility-side of the meter. We have argued that there are both DG demand-side management (DSM) and supply-side management (SSM) applications respectively. We believe that 10 MWs is an appropriate size limit now in terms of rated capacity for DG, given the current progress with national standards. In implementation, we believe the restrictions on capacity should not be arbitrary, but determined through appropriate studies, such as an interconnection requirements studies that would be performed by the utility. Finally, HREA believes the Parties all understand there will be emerging DG technologies seeking to enter the market, e.g., solar air conditioning (SAC) configured as a CHP, fuel cells, storage systems, etc. The challenge will be how to identify, evaluate and introduce these technologies in the most efficient manner. We believe that task can be handled in IRP, as discussed below.

2. Who should own and operate distributed generation projects?

HREA Re-Stated Position:

We believe that DG projects are best implemented by industry via third party sales or lease agreements with customers. Consequently, the customer could choose to own the project (in which case we would probably the highest value for this investment) or lease (as would effectively be the case in a performance contract with a third party). We continue to oppose ownership by regulated investor-owned utilities (IOUs), but are not opposed to ownership by an unregulated, utility-affiliate. We believe ownership by a cooperative, such as the Kauai Island Utility Cooperative, requires further discussion, and remain open on the subject of their ownership of DG.

HREA has developed a sound argument against direct IOU participation, as first postured in our PSOP, and then backed up with our DT-1 testimony (Section III), and RT-1 testimony (Sections I and III). Our argument is based on the principle that the IOU should not be involved directly in DG projects on the customer side of the meter. The customer has several options to reduce his load, including conservation (e.g., cutting back on electricity use and use of solar hot water systems to avoid the need for electricity), traditional energy-efficiency measures, net energy metered renewable systems, and CHP. These options are all load reduction measures, NOT utility supply options, and should all be supported and facilitated by the utility as demand side measures. It makes no sense for the utility to be the one installing solar hot water systems. We feel the same way about CHP.

Furthermore, we have found NO precedents for utility DG projects. Instead, there are precedents for NO utility participation from the states of New Mexico, Louisiana and Pennsylvania, which support our position.[7] Specifically:

a. Public versus Private Utility Services. Customer-cited DG is not considered a public utility service in the states of Louisiana and Pennsylvania. Instead, a DG facility owned by an unregulated entity or third party is considered a private utility that provides electricity and/or thermal power to a limited number of identifiable customers. This is in contrast, to a public utility that would provide electricity to all the customers on the grid. Thus, HREA believes a third party providing a DG service to a customer should be considered a private utility;

b. Concept of "utility-related, non-utility" services. In New Mexico, a pubic utility sought to provide additional types of services, and not specifically CHP, on a tariff basis. The New Mexico PUC, in ruling against the public utility, considered the services to be "utility-related, non-utility" in nature, and optional from the perspective of the customer. This ruling was upheld by a state Supreme Court in New Mexico. HREA believes that provision of DG, including CHP, by its nature is a utility-related, non-utility service; and

c. Legal issue regarding joint sale of electricity and thermal power by a monopoly IOU. We are not aware of a precedent that would allow a monopoly IOU, such as HECO, to sell both electricity and thermal power and that is an issue that we feel needs further investigation.[8] Thus, HREA questions whether HECO's proposed CHP Program would be legal.

[7] See HREA RT-testimony, pages 8 to 11 for details. Note also: County of Maui (COM) RT-1 testimony on page 7 for a similar argument against IOU participation in customer-sited DG. See also County of Maui

Finally, despite the HECO's claims that their direct participation in the CHP market is warranted to allay fears of safety and reliability problems, and negative impacts on non-CHP customers, we do NOT find their arguments to be persuasive. Specifically:

a. HECO has not provided evidence that existing, third-part CHP systems have caused problems on HECO's systems, and

b. HREA has provided in our RT-1 testimony, including an analysis of HECO's proposed CHP program and tariff, raising questions regarding HECO's claims that their customers would be better off with HECO's direct participation in the CHP market.

3. What is the role of the regulated electric utility companies and the Commission in the deployment of distributed generation in Hawaii?

HREA's Re-Stated Position:

HREA believes role of the regulated IOU (HECO) should be to facilitate the DG market through IRP. See our response to Issue 12, regarding recommended changes to IRP to facilitate the DG market.

Through creation and implementation of administrative rules, the PUC should ensure that:

a. All DG providers have unrestricted access to the market,

b. Interconnection and operational requirements, including power purchase agreements, are fair and equitable to all parties, and

c. The utility deals with all DG providers in a fair and even-handed manner.

RT-1 testimony, Exhibits COM-R-101 and COM-R-102, and similar arguments regarding public versus

Impact Issues:

Overall: HREA believes it is important to study the impacts of DG, both positive and negative, in order to assess the overall costs and benefits of planning for and implementing DG.

4. What impacts, if any, will distributed generation have on Hawaii's electric transmission and distribution (T&D) systems and market?

HREA's Re-Stated Position:

Our position remains basically the same as provided in our PSOP. We believe the impacts will be primarily positive, especially if DG is planned and implemented under IRP. For example, as re-stated from our PSOP:

- DG will help increase the overall reliability of our island grids, i.e., the addition of generators on the system increases reliability. Specifically, the probability of multiple generators failing at the same time decreases, improving reliability of the system. Also, individual failures will be mitigated to the degree that the DG will be smaller in capacity and their impacts will be less that larger generators (e.g., the loss of a 2 MW DG will much less of an impact of the loss of a 200 MW CG);
- DG can be implemented to defer or avoid T & D upgrades and new T & D (such as with new construction of hotels and resorts); and
- DG can be implemented to provide rate relief to specific customers without impacting other ratepayers negatively. Initially, DG will be off-setting new demand. Thus, DG will defer new fossil central generation (CG) and help defer and perhaps avoid rate increases, if it implemented in an innovative and competitive manner, and DG is not rate-based. However, if DG is rate-based, ratepayers will likely be subjected to rate increases as they have historically been with the installation new CG.

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private use on pages 4 to 7.

5. What are the impacts of distributed generation on power quality and reliability?

HREA's Re-Stated Position:

Our position remains basically the same as provided in our PSOP as re-stated below:

Power Quality. We believe that power quality from DG will equal or exceed the utility's existing power quality. In general, power quality can be assured if DG meet applicable Institute of Electrical and Electronic Engineers (IEEE) standards and are certified by the Underwriter Laboratory (UL) or other certification entities. However, there will be times when a technical definition of power quality may be required, and, perhaps, in situ testing to confirm the power quality of a specific DG.

Reliability. Reliability can be defined a number of ways. For example, reliability is typically the probability of a given event, such as continuous operation of a generator or a transmission system (i.e., no failures). As noted above, DG will help increase the overall reliability of our island grids, i.e., the addition of generators on the system increases reliability, as the probability of multiple generators failing at the same time decreases, and individual failures will be mitigated to the degree that DG will be smaller in capacity.

Reliability can also be defined more specifically in terms of percentage of the time the DG is available to generate and deliver electricity, as opposed to being down, due to routine maintenance or for repairs. This percentage, however, is usually referred to as the DG or generator availability.

A third definition relates to whether the DG is delivering power at a specific time. For example, a fossil generator is typically viewed as highly reliable, and considered to be firm power, i.e., you can turn it on when you want it and it will be there

[8] Reference our closing comments in the Hearing.

(assuming you have fuel). A wind turbine can only generate electricity, if there is sufficient wind, and is therefore, considered intermittent or as-available by the utility. Consequently, firm power is given more value by the utility.

Notes: system availabilities for wind turbines, PV, geothermal and hydro (all of which are considered intermittent), can be very high, even higher than fossil generators. However, the power delivery reliability of all generators is a function not only of their system availabilities, but also on the availability of their resource, such as the wind, the sun, geothermal fluids, and water for renewables, and the specific fossil fuel for conventional generators.

6. What utility costs can be avoided by distributed generation?

HREA's Re-Stated Position:

Our position remains basically the same as provided in our PSOP. We defer to other parties that may be able to provide quantitative assessment of the utility costs that can be avoided by DG. Qualitatively, we believe there are a number of utility costs that can be deferred and/or avoided by DG including (from our PSOP):

- Cost of new generation: If aggressively implemented, DG can defer and possibly avoid the need for new CG. If implemented competitively (hence no rate-basing of DG), the utility costs for new CG can be avoided;
- Avoided line losses: implementation of DG will reduce line losses. Hence, utility costs associated with line losses can be avoided;
- Avoided T&D upgrades: similarly, implementation of DG, properly planned in IRP, will reduce the need for T&D upgrades. Hence, utility costs associated with T&D upgrades can be avoided; and
- Cost for spinning reserve: Spinning reserve can help improve system reliability and also provide load-following capability. Not all of the islands

have a spinning reserve policy. With the installation and DG, it may be possible to reduce spinning reserve requirements, and those costs could be avoided by the utility.

7. **What are the externality costs and benefits of distributed generation?**

HREA's Re-Stated Position:

Our position remains basically the same as provided in our PSOP. We defer to other parties that may be able to provide quantitative assessment of the externality costs and benefits of DG. We believe a number of potential externalities can be identified, but achieving consensus on how to monetize the externalities may be difficult, short of an international, Kyoto-style agreement made by the federal government. That type of agreement would most likely result in requirements to reduce carbon emissions and might include monetization of certain emissions, such as carbon dioxide. We include below, from our PSOP, examples of externality benefits of DG, which are:

a. <u>Reduction in fossil fuel emissions</u> from conventional generators, e.g., carbon dioxide (CO_2), nitrogen oxides (NO_X), sulfur oxides (SO_X) and particulates. The amounts of these emissions can be calculated for each conventional generator, and the total amount of emissions avoided per MWH based on the operational profile of each of the utility grids;

- <u>Conservation of Water</u> needed to cool conventional generators, e.g., steam turbine generators. Similarly to the air emissions, water usage can be calculated for each conventional generator and expressed as the number of gallons per MWH based on the operational profile of each of the utility grids;
- <u>Energy Security</u> benefits from DG accrue based on the reduction of fossil fuel needs. These benefits would include: reduced risks associated with

energy supply, such as supply disruptions due to political or terrorist events, and risks associated with oil spills at sea or in the islands;

- Energy price risk benefits accrue when renewables, energy conservation and/or conventional energy efficiency measures are substituted for fossil fuels, i.e., if we don't use any fossil fuel, we wouldn't have to worry about oil price fluctuations. Consequently, the price risks are reduced as we reduce our dependence on oil. Additional benefits accrue, but to a lesser degree, when CHP, are employed. Nevertheless, while fuel prices tend to fluctuate independent of the Hawaii market, we can hedge our overall energy price risks by reducing the amount of fossil fuels we import.

8. What is the potential for distributed generation to reduce the use of fossil fuels?

HREA's Re-Stated Position:

Our position remains basically the same as provided in our PSOP, and is re-stated below. We believe there is significant potential for DG to reduce the use of fossil fuels Hawaii. For example:

- Based on a renewable study conducted by WSB-Hawaii for the Hawaii Energy Policy Forum, there is potential (based on implementing wind, solar and biomass projects) to double our renewable energy percentage in Hawaii in 2003 (about 6%) to 11.7% in 2008, and more than double the percentage in the subsequent 10 years to 28.6% in 2018. (For details, see the report at http://hawaiienergypolicy.hawaii.edu/papers/bollmeier.pdf); and
- Twenty to fifty percent of current building demand could be saved through energy conservation and energy-efficiency measures including CHP.

Implementation Issues:

Overall: HREA believes there is consensus on the need to promote DG. We believe the primary issues still revolve around who gets to play, what the market looks like and what are the rules.

9. **What must be considered to allow a distributed generating facility to interconnect with the electric utility grid?**

HREA's Re-Stated Position:

Since the issues of DG ownership are covered elsewhere in this re-stated SOP, we will focus on the technical and administrative aspects of interconnection. In our PSOP, we listed a number of items to consider for allowing a distributed generating facility to interconnect with the electric utility grid. In the subsequent pleadings and the hearing, HREA believes a number of specific issues have emerged. Specifically:

a. <u>Component and Facility Standards</u>. All DG components and facilities should meet or exceed applicable National Electric Code (NEC), Institute of Electrical and Electronic Engineers (IEEE) standards, such as IEEE-1547 and its subsequent revisions and related standards;

b. <u>Certification of Components and Facilities</u>. DG components and facilities should be certified to those standards, as appropriate, by the Underwriter Laboratory (UL), or other authorized certification agencies or entities;

c. <u>Expedited Approval of Interconnection Agreements</u>. To facilitate safe, rapid deployment of DG, standard interconnection agreements should be developed and implemented. We would like to note the progress already made and remaining issues:

    - <u>Net Metered Renewable Systems</u>. Parties have noted that a simplified agreement is already in place for net metered renewables systems up to 10 kW and HECO has submitted to the PUC additional agreement for net metered systems from 10 kW to 50 kW;

- Demand-Sited DG. HECO has proffered Rule 14H to facilitate the interconnection of CHP. Rule 14H does not specify a limit on the capacity (in kWs or MWs) of CHP, but we believe the Parties understand that interconnection studies will be required of individual projects, depending on their capacity and location on the grid. During the Hearing[9], Warren Bollmeier identified the need for an optional section for a power purchase agreement in a CHP interconnection agreement in order to expedite negotiations; and

- Supply-Side DG. HREA observes that there may be need to develop and implement a simplified interconnection and power purchase agreement for supply-side DG.

d. HREA Recommendation. In light of the issues identified above and other potential issues, HREA recommends that the PUC establish a working group to assist the PUC in monitoring the overall development and implementation of DG interconnection agreements and power purchase agreements.

10. What are the appropriate rate design and cost allocation issues that must be considered with the deployment of distributed generation facilities?

HREA's Re-Stated Position:

In our PSOP, we indicated that an appropriate rate design can help facilitate the implementation of DG, and cost allocation issues should be addressed in a way that will also help facilitation of DG. Since then, we believe that the parties have pushed the discussion much further down the road, in part, by looking at specific proposals. The following is an update to our PSOP:

[9] Hearing, Day 2, Panel F, reference: pages 175 to 177 of the Day 2 transcripts.

a. Rate Design. HREA believes:

- Tiered-Rate System. A tiered-rate system (where increasing levels of usage are billed at a higher rate), combined with a low customer charge could be implemented to encourage DG, especially for residential customers. Such a system would encourage the customer to investigate DG measures to reduce site load. Note: a tiered-system approach could also obviate the need for current, low-income user subsidies;

- Time-of-Use Rate. A time-of-use rate may be more appropriate for commercial customers. This rate approach may also be help shift utility peak loads;

- Standby-Rates. The sometimes provocative discussion on standby-charges versus demand charges versus has raised some interesting questions. For example, should there be both a standby and a demand charge to a DG customer? If so, HREA believes the demand charge should be based on the net demand required from the utility and standby-charges should be based more on actual usage than an upfront reservation fee. Thus, HREA believes its position comports with that of the County of Maui;

- Where from here? HREA concludes that a separate docket on utility rate design and stand-by service may be required to resolve all the issues.

b. Cost Allocation/Recovery Issues. The sometimes provocative discussion on standby-rates versus demand charges has raised some interesting questions that go to the core of our current approach on how the utility is allowed to recover its costs.

The existing goal of rate recovery appears to be based on the principle of cost causation, i.e., recover the demand costs from the customer in the form of a demand charge, recover usage costs from the customer in the form of a usage charge, and a customer charge to cover certain administrative costs. In practice, however, this is not being done evenly. For example, residential customers pay basically a customer charge and a usage charge, while commercial customers pay a customer charge, a demand charge and a usage charge. There also issues of cross-subsidies between and within customer classes. HREA recommends that the commission consider:

- Basing rate recovery from all customers primarily on a usage charge, much the same as is done by grocery stores, airlines, hotels and other industries. The demand and usage costs could still be accumulated and accounted as they are now. However, in removing demand charges, the usage rates would obviously need to be increased for commercial/industrial customers and decreased to correct cross-subsidies, if desired; and
- Identifying values for the DG and consider these values as off-sets when determining demand charges and standby-service charges to DG customers.

11. What revisions should be made to the integrated resource planning process?

HREA's Re-Stated Position:

DG should be given a very high priority in IRP and be planned to help meet our electricity demand and requirements, such as our existing Renewable Portfolio Standard (RPS) law and any future amendments to the law. In this regard, the output of IRP should include be an optimal mix of DG measures.

<u>Recommended Planning Approach</u>. The utility should plan for and facilitate implementation of DG through IRP, both as demand-side management (DSM)

alternatives and supply-side management (SSM) alternatives. This is not currently being done by HECO. DG (including CHP) are evaluated separately from SSM and DSM alternatives. Specifically, HREA recommends that all DG be evaluated with SSM and DSM alternatives as follows:

i. DSM Alternatives. HREA believes all DG on the customer-side of the meter, whether utility-owned (should that be allowed) or non-utility, should be incorporated under the DSM program in IRP. The costs and benefits of DG-DSM's should be evaluated along with all other DSM's. HREA believes further that specific DSM program elements should be tailored for each desired technology on each of our island grids. Following the structured competition market model that HREA has proposed, the utility would market and facilitate each DSM program element in a similar manner to what is done on existing programs, such as for solar hot water (SHW) systems. Finally, perhaps not all DG technologies need incentives. In any case, incentives could be designed and utilized to level the field among all DG-DSM technologies;

ii. SSM Alternatives. HREA believes all DG on the utility-side of the meter, whether utility-owned (should that be allowed) or non-utility, should be incorporated under the SSM program in IRP. The costs and benefits of DG-DSM's should be evaluated along with all other SSM's. Since HREA supports competitive bidding on all supply-side resources, HREA believes the utility should acquire all SSM's, including DGs, via a competitive bidding process;

iii. Identifying Load Pockets. It may be possible to identify specific load pockets (as has been suggested by the CA and HREA). If so, the utility could then solicit proposals to off-set specific loads and provide certain T&D benefits. If it is not possible, the utility could create DG-DSM programs for specific technologies, in a similar manner, once again, as is done on the SHW DSM; and

iv. Overall Planning. Regarding the overall planning in IRP, HREA believes that estimates of the desired DG-DSMs, whether including load packets or only in the aggregate, would be provided as inputs to adjust the demand forecast for each of our island grids. HREA believes this is exactly the approach already in place on the SHW-DSM program element. This approach can serve as the model for incorporating new DSM program elements for DG, including CHP.

.Recommended Implementation Approach. A DG implementation plan should be prepared as part of IRP, and subsequently, tracked once the IRP has been approved by the PUC. The plan should include:

a. a specification of which DG measures will be included;

b. a procurement plan that includes preliminary specifications for desired DG additions, a timeline and selection criteria; and

c. development and implementation of standard interconnection agreements, with options for power purchase agreements, for applicable DG in order to expedite contract negotiations.

12. What forms of distributed generation (e.g., renewable energy facilities, hybrid renewable energy systems, generation, and cogeneration) are feasible and viable for Hawaii?

HREA's Re-Stated Position:

See our response to Issue #1.

13. What revisions should be made to state administrative rules and utility rules and practices to facilitate the successful deployment of distributed generation?

HREA's Re-Stated Position:

Our position has not changed since our PSOP and is re-stated here. We believe a new that revisions to the following existing administrative rules may be required:

- HAR6-61-Rules of Practice and Procedure before the Public Utility Commission;
- HAR6-74-Standards for Small Power Producers and Cogeneration; and
- Title VII, General Order No. 7, Standards for Electric Utility Service in the State of Hawaii.

We also believe it may be appropriate to develop a specific administrative rule for the Distributed Generation.

We reserve the right to make more specific recommendations at a later time.

14. The Parties and Participants may also address general issues regarding distributed generation raised in the informal complaint file by Pacific Machinery, Inc., Johnson Controls, Inc. and Noresco, Inc. against HECO, MECO and HELCO on July 2, 2003 (Informal complaint No. IC-03-098), but not specific claims made against any of the Parties named in the complaint.

HREA's Re-Stated Position:

Our position remains the same as provided in our PSOP. We observed that many of the issues raised by Pacific Machinery, Johnson Controls and Noresco identical to, are similar to or expand the discussion of the previous 13 issues. Some of the issues raised by Pacific Machinery, Johnson Controls and Noresco are new. However, we provided no detailed comments on the issues raised by the Pacific Machinery, Johnson Controls and Noresco, but reserved the right to provide comments at a later time. HREA does have one additional comment. At this time, we are disappointed that Pacific Machinery and Johnson Controls withdrew from this docket. We believe their participation would have provided invaluable information to the record of this docket.

DATED: March 7, 2005, Honolulu, Hawaii

President, HREA

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Opening Brief upon the following parties by causing a copy hereof to be hand-delivered or mailed, postage prepaid, and properly addressed the number of copies noted below to each such party:

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